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Vice President, Regulatory Affairs & Chief RIsk Officer

BY COURIER, RESS AND COURIER

November 11, 2019

Ms. Christine E. Long
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long,

EB-2019-0082 – Hydro One Network's 2020-2022 Transmission Rates Application – Undertaking Responses

Attached please find the following undertaking responses in respect of the above noted proceeding:

J 3.8	J 6.6	J 8.3
J 4.2	J 6.7	J 8.4
J 4.6	J 7.1	J 8.5
J 4.9	J 7.2	J 8.6
J 5.5	J 7.3	J 8.7
J 5.6	J 7.8	J 8.8
J 6.1	J 7.9	J 8.9
J 6.2	J 8.1	J 9.3
J 6.5	J 8.2	

This filing has been submitted electronically using the Board's Regulatory Electronic Submission System and two (2) hard copies will be sent via courier.

Sincerely,

ORIGINAL SIGNED BY KATHLEEN BURKE
Frank D'Andrea
Encls.
cc.EB-2019-0082 parties (electronic)

UNDERTAKING J3.8

Reference:
SR-11

Undertaking:
To provide a status update on the SONET system replacement project

Response:
In 2020, the SONET system replacement project will continue in the development and estimation phase. In 2021, project execution will begin, consistent with the plan included in this Application.

UNDERTAKING J4.2

Reference:
I-07-SEC-27, JT-1.12

Undertaking:
To provide a list of the test-year projects.

Response:
Attachment 1 provides a listing of the 563 investments which are referenced in the interrogatory response for I-07-SEC-27 and presented in a similar format as undertaking JT-1.12. As discussed during the hearing, only investments greater than $3M have been described and investments less than $3M have been consolidated into a single line item.

Grouping	Category	Type	Less than $3M	Description	Project Count	Test Year Total ($ in millions, NET)	Risk Mitigation ($)
Test Year Expenditures	1. System Access	Mandatory		Connect New DESN near Halton TS	1	6	-
				Horner TS - Build 230-28-28kV Station	1	4	-
				IAMGOLD - 115 kV Connection	1	10	-
				Tx Load Connection Plans	1	10	-
			Less than $3M		23	16	-
			Less than $3M		2	3	-
	2. System Renewal	Mandatory		Telecom Capital Lease Renewals (Fiber IRU Agreements)	1	11	3,190,264
				Nanticoke ABCB Station Refurbishment Project	1	45	5,269,590
				Cherrywood TS 230kV - Phase 1 ABCB (12) & AC/DC SS	1	44	5,628,346
				Tx Lines Emergency Replacement	1	29	1,992,879
				N21W/N22W, Sarnia Scott TS-Buchanan TS, Str. Refurb.	1	5	293,216
				Detweiler TS: T2, T4 & Component Replacement	1	14	251,406
				Line Refurbishment - D2L, Upper Notch JCT x Martin River JCT	1	3	145,930
				B5/6C, BurlingtonTS X WestoverCTS, Tx Line Refurb.	1	5	145,930
				Pine Portage SS: Component Replacement	1	6	62,270
				Strachan TS: T12 & Component Replacements	1	4	21,487
				Bridgman TS: T11, T12, T13, M/C & Component Replacements	1	30	43,746
				Leaside TS: 27.6kV Yard & Component Replacements	1	10	21,795
				Kenilworth TS: T1, T3, T4 & Switchyard Refurbishment and Reconfiguration	1	16	23,632
				Sheppard TS: T3, T4, PCT, LV Yard & Component Replacements	1	5	29,239
				Beck 2 TS 230 kV ABCB Replacement	1	33	-
				Bruce A TS 230 kV ABCB Station Refurbishment	1	6	-
				CIPv6 Transient Cyber Assets Project (SFAD)	1	3	-
				Elgin TS T1/T2/T3/T4; T1,T2,T3,T4 MVGI and Component Replacement	1	10	-
				Hanmer TS: Northern Station Replacement Project	1	8	-
				Hawthorne TS - ISCR	1	3	-
				Lennox TS BULK: ABCB component replacement	1	16	-
				Martindale TS: T21/T23 & Component Replacement	1	18	-
				Physical Security ISL Application Replacement	1	6	-
				Transformer Protection Replacement due to 2nd Harmonic Misoperations	1	4	-
			Less than $3M		62	65	4,657,419
				Trafalgar TS: Component Replacements	1	18	22,774,659
				Milton SS: Component Replacements	1	10	12,748,846
				Claireville TS: Component Replacements	1	22	12,177,368
				Fort Frances TS: Component Replacement	1	12	7,475,555
				Essa TS BULK; ABCB & Component Replacement	1	27	16,490,443
				Bruce B SS ABCB Replacement project	1	50	14,448,901
				Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement	1	31	5,197,186
				Tillsonburg TS: Component Replacement	1	6	849,325
				Middleport TS; ABCB Station Refurbishment	1	61	11,839,484
				Wawa TS: Component Replacement	1	4	3,315,152
				Q25BM/Q29HM ADSS Replacement	1	4	484,854
				Cherrywood TS 230 & 500 kV: Phase 3 ABCB (26)	1	24	14,060,530
				Mackenzie TS: Component Replacement	1	11	1,735,950
				Rabbit Lake SS: Component Replacement	1	7	641,267
				Runnymede TS: T3, T4 & Switchyard Replacement	1	13	1,923,339
				Bunting TS: MV Switchgear & Component Replacement	1	6	1,294,240
				Beck 1 SS 115kV ABCB Replacement	1	10	2,240,565
				Otto Holden TS: T3/T4 & Component Replacement	1	25	2,988,313
				Sarnia Scott TS: T5 & Component Replacement	1	13	1,799,180
				Fairbank TS: T1, T2, T3, T4, PCT & LV Yard Replacements	1	56	4,665,254
				Murray TS: T11, T12 & Component Replacement	1	14	1,280,770
				Carlton TS: T1, T4 & Switchyard Refurbishment and Reconfiguration	1	12	1,365,519
				Near-Term Deteriorated Asset Replacement Program	1	15	2,029,402
				Wingham TS: T1, T2, PCT & Component Replacement	1	18	1,229,358
				Kirkland Lake TS: Component Replacement	1	12	708,734
				Tower Foundations - L0- Vulnerable	1	57	6,374,390
				Arnprior TS: T1/T2 and PCT and Component Replacment	1	23	1,534,825
				Manby TS: T7, T9, T12, T13 & Component Replacements	1	4	3,029,988
				Demand Capital - Power Transformers	1	18	1,959,698
				Gage TS: T3,T4,T5,T6, PCT & Switchyard Reconfiguration	1	31	1,827,573
				Wood Pole Structure Replacements - Publicly Accessible, High Criticality	1	78	6,891,178
				Wood Pole Structure Replacements - Publicly Accessible, High Criticality	1	78	6,891,178
				Lauzon TS: T6, T8 & Component Replacement	1	17	1,449,796
				Moose Lake TS: Component Replacement	1	13	981,875
				Glendale TS: T1, T3, T4 & Switchyard Refurbishment and Reconfiguration	1	40	1,874,052
				Telecom Performance Improvements	1	11	442,416
				Hanover TS: T2 & Component Replacement	1	5	1,163,104
				Port Colborne TS: T61, T62 & Switchyard Refurbishment	1	30	1,133,007
				Hunta SS: Component Replacement	1	6	263,121
				Wonderland TS: T5, PCT & Component Replacement	1	23	885,994
				Minor Component Demand Capital	1	27	2,029,402
				Rexdale TS: Metalclad Switchgear & Component Replacement	1	19	681,515
				Hanlon TS: T1, T2 & Component Replacement	1	19	574,339
				Kingsville TS: T1, T2, T3, T4 & Component Replacement Phase 2	1	20	594,206
				Telecom Performance Improvements	1	6	281,883
				Finch TS: Component Replacements	1	18	678,375
				Lambton TS: T5 & Component Replacement	1	26	893,869
				Stanley TS: T2, PCT & Component Replacement	1	23	696,627
				Thorold TS: T1, MV Switchyard & Component Replacement	1	16	374,269
				King Edward TS T3 and PCT Replacement	1	8	226,767
				Halton TS: Breakers, PCT & Component Replacements	1	7	187,080
				Marathon TS: Component Replacement	1	17	358,549
				Tx Line Refurb. K1/K2 | Kirkland Lake TS-Holloway Holt JCT (Copper)	1	3	107,473
				Tx Lines Insulator Replacement Program - Non-Publically Accessible, High Criticality	1	102	3,068,769
				John Transformer Station Reinvestment	1	40	1,447,792
				Tx Lines Insulator Replacement Program - Non-Publically Accessible, High Criticality	1	102	3,068,769
				Q2AH, ROSEDENE JCT X ST.ANNS JCT, Tx Line Refurb	1	8	114,674
				Ottawa Ring 9 Fibre Infrastructure Development	1	9	139,421
				Bruce A TS: 500kV ABCB replacement and Yard Reconfiguration	1	47	1,857,193
				Mobile Radio System Replacement	1	15	201,590
				Campbell TS: PCT & Component Replacement	1	5	155,249
				H24S Martindale x Widdifield Completion of OPGW Path	1	5	45,201
				Replace Legacy SONET Systems	1	58	1,008,208
				Tx Line Refurb. B3/B4 | Horning Mountain JCT-Glanford JCT (Copper)	1	4	156,191
				Buchanan TS: 115 kV Switchyard & Component Replacement	1	4	199,544
				Metalclad Breaker Replacement Program - Carryover	1	5	31,652
				Tx Line Refurb. H1L/H3L/H6LC/H8LC | Bloor Street JCT-Leaside 34 JCT (EoL)	1	18	114,674
				Tx Line Refurb: Placeholder, Expected EoL Line Discoveries	1	98	1,065,455
				Tx Line Refurb. D6 | Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT (Close EoL)	1	12	104,636
				Porcupine TS: Component Replacement	1	11	250,626
				Keith TS: T11,T12 & Component Replacement	1	32	159,937
				Tx Lines Shieldwire Replacement - Non Publically Accessible, High Criticality	1	14	107,721
				Purchase of Transformer Operating Spares	1	43	311,494
				Tx Line Refurb. D2/3H & D4 & D6T, Hunta SS X Abitibi Canyon SS (EoL)	1	27	113,546
				Elliot Lake TS: Component Replacement	1	5	65,423
				Tx Line Refurb. A8K/A9K | A8K Str. 141 JCT-A8K Str. 277 JCT-Ramore JCT (Copper)	1	24	99,074
				Tx Lines Shieldwire Replacement - Non Publically Accessible, High Criticality	1	24	107,721
				Orangeville TS: T1, T2, T3, T4 & Component Replacements	1	36	93,363
				Bridgman TS: Building Renewal, HL A1/A2 & A7/A8 Swgr Replacement	1	10	27,304
				N5K, Sarnia Scott TS X Kent TS, Tx Line Refurb.	1	5	62,536
				Slater TS T1/T2/T3 and component replacement	1	12	20,814
				Tx Line Refurb. E1C | Ear Falls TS-Slate Falls DS (EoL) + Etruscan JCT-Crow River DS (Near EoL) - EOL, PA	1	33	75,810
				Duplex TS: T1, T2 & Component Replacements	1	4	52,799
				Tx Line Refurb. A4H/A5H | C.P. Tunis JCT-Fournier JCT (Close EoL)	1	18	27,031
				HV UG Cable - Replace C5E/C7E	1	63	176,963
				Minden TS T1, T2, PCT & Component Replacements	1	18	39,690
				Tx Line Refurb. M6E/M7E | Cooper's Falls JCT-Orillia TS (Near EoL)	1	24	32,870
				Cedar TS: T7, T8 & Component Replacement	1	9	14,585
				Tx Line Refurb. A7L/R1LB & 57M1 Alexander B JCT-Lakehead TS & Nipigon JCT Copper	1	56	89,257
				Tx Line Refurb. A4L | Roxmark Mines CTS-Beardmore JCT/DS #2 (Near EoL)	1	14	24,987
				Tx Line Refurb. B5QK | Barrett Chute #2 JCT-Sharbot JCT (Near EoL)	1	17	32,552
				Birmingham TS: MV Switchgear Replacement	1	4	27,193
				Tx Line Refurb. L22H Easton JCT-Hinchinbrk N JCT Near EoL	1	20	37,517
				Crowland TS: T5, T6 & Component Replacement	1	16	18,587
				Belleville TS- Station Refurbishment	1	10	8,519
				Newton TS: T1, T2, PCT & Switchyard Refurbishment	1	6	13,268
				Algoma TS: T5/T6 & Component Replacement	1	7	23,273
				Tx Line Refurb. E8V/E9V | Orangeville TS-Essa JCT (Near EoL)	1	18	21,990
				Tx Line Refurb. C27P | Galetta JCT-Bannockburn JCT (Near EoL)	1	79	31,293
				Tx Line Refurb. T2R/T61S | Timmins JCT-Wawaitin JCT-Shiningtree JCT (Close EoL)	1	32	12,814
				Parry Sound TS: Component Replacement	1	14	4,913
				Main TS: T3, T4 & Component Replacements	1	26	7,309
				Tx Line Refurb. D1M/D2M/D3M/D4M | Otter Creek JCT-Minden TS (Close EoL)	1	4	17,814
				Tx Line Refurb. C28C, Complete Line, Chats Falls SS X Cherrywood TS Near EoL	1	4	17,814
				CIP-014 Implement Remaining 24 sites	1	54	-
				Steel Structure Coating Program	1	55	-
			Less than $3M		108	234	49,623,429
	3. System Service	Mandatory		Aylmer Tillsonburg Area Tranmission Reinforcement	1	29	-
				Customer Power Quality (Tx) - Capital - Cap Switcher	1	10	-
				East-West Tie Connection	1	102	-
				Kapuskasing area reinforcement - Kapuskasing TS	1	10	-
				Leamington Area Transmission Reinforcement	1	74	-
				Lennox 500kV Shunt Reactors	1	30	-
				Local Area Supply - Regional Plans	1	25	-
				M30A/M31A Conductor Upgrade	1	23	-
				Northwest Bulk Transmission Line Project - Construction	1	30	-
				Richview Manby Transmission Reinforcement -Station	1	7	-
				Southwest GTA Transmission Reinforcement	1	18	-
				St. Lawrence TS: Replace Phase shifters PS33/PS34	1	18	-
				Upgrade Barrie TS and Line E3/4B to 230 kV	1	69	-
				Watay Line_to_Pickle Lake Connection	1	26	-
			Less than $3M		21	32	-
			Less than $3M		1	0	-
	4. General Plant	Mandatory		Operating Hardware Refresh	1	6	1,244,481
				NMS Capital Sustainment	1	30	119,119
				Integrated System Operations Centre - New Facility Development	1	45	-
				IVCT Refresh	1	5	-
			Less than $3M		14	20	4,769,810
				SAP Foundation Phase 1 - HR/Pay - CAP	1	6	203,672
				SAP Foundation Phase 2 - Finance -CAP	1	7	287,872
				Local PSMC Network Sustainment	1	12	404,981
				Non-Operational Data Mgmt System New	1	16	25,420
				Transport and Work Equipment (TWE) Capital Requirements - Priority 2 - Heavy PTO	1	28	24,249
				Accomodations and Interior Fixtures and Equipment	1	14	4,020
				TS Facilities & Site Improvements	1	29	-
			Less than $3M		51	85	2,081,813
No Test Year Expenditures					122	-	5,924,415
Grand Total					**563**	**3,992**	**291,648,598**

UNDERTAKING J4.6

Reference:
GP-01

Undertaking:
To confirm that the amount being sought for approval in this application for the ISOC – the revenue requirement and in-service addition – is not based on the transmission-allocated portion of $159.8 million.

Response:
In this application, the total cost for the ISOC is $159.8 million as shown on p.28 of ISD-GP-01. The transmission-allocated portion of this total cost being sought for recovery in this application is $79.8 million or 49.93%, which will be recognized as a transmission in-service addition in 2021 and which is reflected in the proposed 2021 and 2022 revenue requirements as part of the test year rate base.

The total cost for the ISOC as shown in the Hydro One Board of Directors approved business case filed in undertaking response J-4.05, Attachment 1 is $154.5 million. ISD-GP-01 was filed on March 21, 2019 and the business case was approved on August 16, 2019. The total cost savings of approximately $5.3 million during this period was achieved primarily through value engineering – the transmission-allocated portion of the total cost savings is approximately $2.7 million.

Hydro One will update the transmission-allocated costs and hence the revenue requirement and in-service addition being sought for recovery in this application to reflect the lower Hydro One Board of Directors approved business case total cost as part of the Draft Rate Order process in this application.

UNDERTAKING J4.9

Reference:
I-07-SEC-58
Oral Hearing Volume 4, Page 132, Line 26 – Page 136, Line 15

Undertaking:
To update the chart (payroll table) at exhibit K4.5, page 4, to reflect the pension valuation update.

Response:
Please refer to attachment 1 to this undertaking, provided in an Excel format.

Attachment 1 includes the updated payroll table from Exhibit I, Tab 07, Schedule SEC-58 Attachment 1 including:

1. the impact of the updated pension valuation as of December 31, 2018; and

2. the allocation percentages between the Transmission and Distribution, OM&A and Capital, as further explained in J5.5.

UNDERTAKING J5.5

Reference:
I-07-SEC-026
Oral Hearing Volume 5, Page 127, Line 12 – Page 129, Line 24

Undertaking:
To provide the allocation used for the payroll table.

Response:
The allocation percentages have been included in the updated compensation table in response to undertaking J4.09 Attachment 1.

By way of background, in EB-2016-0160 Decision and Order dated September 27, 2017 at pages 56 and 57, the OEB directed Hydro One to improve its compensation tables in Hydro One's then-ongoing distribution proceeding (EB-2017-0049, which was originally filed in March 31, 2017) by including in the tables, among other things: "(g) An exhibit that shows how the allocation factors used to allocate the total compensation amounts between transmission and distribution are derived.…" ("Item (g)").

As directed, Hydro One addressed Item (g) in EB-2017-0049 for distribution rates for 2018-2022. Please see Exhibit C1, Tab 2, Schedule 1, Attachment 6 from that proceeding which is the final form of compensation table arrived at over a number of iterations that were responsive to requests made by OEB Staff and intervenors, and which addressed and discussed Item (g) in detail. The other items (a)-(f) from the EB-2016-0160 Decision and Order are further discussed under J5.6.

Below is a summary of allocation factors and assumptions used to allocate the total compensation amounts between Hydro One's transmission and distribution businesses, along with the evidentiary references where this has been described in this and past proceedings:

- **Total Compensation Calculation:** Total compensation for 2014-2018 is all compensation for all employees employed during the calendar year. Total compensation for 2019-2022 is derived by using total planned FTE multiplied by estimated average salary by representation, with standard escalation assumptions.

- **Allocation Methodology for Regular and Temporary Employees:** Where employees work on both transmission and distribution work activities, their time is allocated using the Black & Veatch methodology. More specifically, to estimate total labour spending in 2020 to 2022, the Black & Veatch ‘Review of Overhead Capitalization Rates’ methodology, as outlined in Exhibit C, Tab 8, Schedule 2, Attachment 1, was applied. The Black and Veatch study uses the Labour Content Method which identifies the estimated percentage of labour spending within transmission and distribution, as between OM&A and capital spending. This allocation method was utilized to estimate the overall compensation allocation between Distribution and Transmission for all regular and temporary employees, but not for casual trades employees.

- **Allocation Methodology for Casual Trades Employees:** For casual trades employees, management expertise was utilized[1] to refine the allocation of planned yearly headcount and the compensation allocation to the transmission and distribution businesses.

- **FTEs:** FTEs were derived using the following assumptions:
    - a budgeted regular position is one FTE;
    - for non-regular positions, unless budgeted for less than one year, a non-regular position is 1 FTE;
    - for casual (Hiring Hall and Casual Construction), an FTE is determined by “person months”/12; and
    - for 2014-2018, FTE’s have been calculated by calculating the average number of employees by representation (# of employees per month/12).

The following table has been embedded in the updated compensation table in J4.9. It summarises the allocation percentages used in the compensation table in this application:

Allocation of Regular and Temporary Staff (Labour Content Method)	**2020**	**2021**	**2022**
Tx Allocation	48%	50%	48%
Dx Allocation	52%	50%	52%
Tx Capital Allocation	74%	76%	76%
Tx OM&A Allocation	26%	24%	24%
Dx Capital Allocation	56%	58%	61%
Dx OM&A Allocation	44%	42%	39%

[1] Compensation costs are allocated by percentage used by the line of business

Allocation of Casual Staff (Management Expertise)	2020	2021	2022
Tx Allocation	42%	44%	45%
Dx Allocation	58%	56%	55%
Tx Capital Allocation (per above)	74%	76%	76%
Tx OM&A Allocation (per above)	26%	24%	24%
Dx Capital Allocation (per above)	56%	58%	61%
Dx OM&A Allocation (per above)	44%	42%	39%

UNDERTAKING J5.6

Reference:
EB-2016-0160
Oral Hearing Volume 5, Page 129, Line 25 – Page 131, Line 10

Undertaking:
Indicate how the compensation table as presented in the current evidence (I-07-SEC-58), addresses the concerns from the Tx 17/18 Decision (EB-2016-0160)

Response:
By way of background, in EB-2016-0160 Decision and Order dated September 27, 2017 at pages 56 and 57, the OEB directed Hydro One to improve its compensation tables[1] in Hydro One's then-ongoing distribution proceeding (EB-2017-0049, which was originally filed in March 31, 2017) by including in the tables seven items labeled (a) through (g). Item (g) is addressed in response to undertaking J-5.05.

As directed, Hydro One addressed items (a) through (f) in EB-2017-0049. Please see Exhibit C1, Tab 2, Schedule 1, Attachment 6 from that proceeding which is the final form of compensation table arrived at over a number of iterations that were responsive to requests made by OEB Staff and intervenors, and which addressed and discussed items (a) through (f) in detail.

On December 12, 2017 Hydro One submitted Attachment 7 and Attachment 8 where it reconciled and explained any differences between the compensation originally presented in EB-2016-0160 under J10.2 and the revised methodology under Attachment 6 in EB-2017-0049.

The summary below provides further information about the evaluation of the compensation table.

Hydro One's Historical Approach
In each of Hydro One's rate applications leading up to the Distribution Application (EB-2017-0049), Hydro One presented total compensation costs at a point in time, specifically, December 31st of each year, for both its transmission and distribution

[1] Previously, response to undertaking J-10.2 filed in EB-2016-0160 was the most up to date compensation table available.

businesses, combined. Hydro One presented combined compensation data for its transmission and distribution businesses for a few reasons: (a) its payroll data systems are limited, and (b) Hydro One believed that the combined data provided continuity between filings and showed trending over multiple applications.

To clarify, evidence in past applications only captured the total compensation for employees on payroll on December 31st, but not all of Hydro One's employees are on payroll at that time. This is particularly true for Hydro One's temporary and casual employees.

Under the historical approach, "total compensation" only included base pay, overtime, short-term incentives, and other allowances for PWU and Society and Management employees. It did not include other compensation items, such as pension and OPEBs.

Exhibit J10.2 in Tx Case (EB-2016-0160)

In the transmission application (EB-2016-0160), in response to requests from parties to that proceeding, Hydro One filed its response to undertaking J-10.2 which showed, on a best efforts basis, its total compensation data with the following changes:

- an expanded definition of total compensation, which included long-term incentives, employee stock options, payroll burdens, and pension and OPEBs; and
- total compensation data for only its transmission business, applying the "labour content" method from the Black & Veatch study "Review of Overhead Capitalization Rates" (filed as Exhibit B1-3-10-1 in the Tx Case) to the combined transmission/distribution compensation data.

It is important to note that undertaking response J10.2 still reflected compensation costs for only those employees on payroll on December 31st.

Attachment 6 in Hydro One's Distribution Application (EB-2017-0049)

Hydro One improved its compensation evidence filed in the Distribution Application on March 31, 2017. Specifically, Appendix B of Exhibit C, Tab 2, Schedule 1:

- uses the expansive definition of "total compensation", consistent with Exhibit J10.2 in the Tx Case;
- reflects total compensation costs for full years, rather than a point in time, which is inconsistent with Exhibit J10.2 in the Tx Case;
- refines the allocation of casual employee compensation based on management's expertise regarding the relative contribution of casual employees to the transmission and distribution work programs;

- isolates total compensation costs for its distribution business only; and
- reflects the Distribution Business Plan (vintage December 2016).

In the transmission application (EB-2016-0160), the OEB ordered Hydro One to file additional evidence on compensation in the Distribution application (EB-2017-0049). In response, Hydro One filed Attachment 6 which shows total compensation for its transmission and distribution businesses, using its improved approach.

Differences between J10.2 and Attachment 6

The following table summarizes the main differences between J10.2 and Attachment 6.

	Exhibit C1-4-1-1 (TX Case EB-2016-0160)	**Exhibit J10.2 (Tx Case EB-2016-0160)**	**Attachment 6 (EB-2017-0049)**
Compensation Data	Based on compensation for employees on payroll December 31st	Based on compensation for employees on payroll December 31st	Based on compensation of all employees employed in the year
Compensation Elements	Base salary, Overtime, Incentive (STI) and other allowances	Base pay, burdens, other allowances, STIP, LTIP, ESOP, Share Grants	Base pay, burdens, other allowances, STIP, LTIP, ESOP, Share Grants
Headcount/ FTE's	Based on year-end headcount	Based on year-end headcount	Total & year-end count provided but FTE's used to calculate compensation costs
Compensation Costing	Average unit cost X headcount X escalation based on negotiated wage escalation/budget non represented wage escalation	Average unit cost X headcount X escalation based on negotiated wage escalation/budget non represented wage escalation	FTE X average unit cost X escalation based on negotiated wage escalation/budget non represented wage escalation
Allocation methodology	No allocation	Black and Veatch	Black and Veatch for regular employees. Casual employees compensation costs allocated by % used by line of business

Current Transmission Application and Compliance with EB-2016-0160 Decision

The compensation template from the Distribution application (EB-2017-0049) Attachment 6 was used to produce the data filed under the current Transmission Application (EB-2019-0082).

The following table summarizes how Hydro One has complied with the Transmission decision in EB-2016-0160.

OEB Decision	Hydro One Response
a) Tables comparable to the year-end payroll tables in the Transmission Payroll Tables for each the years 2014 to 2018 containing total compensation information that reconciles with the combined totals of the amounts for each of the years 2014-2018 allocated to transmission shown in Undertaking J10.2 and the amounts shown for distribution in the Distribution Payroll Tables	a) The current payroll table contains total compensation in each year data rather than year-end compensation only as found in J10.2. Since the current compensation table shows all compensation paid in each year, it is not possible to reconcile with the payroll tables that show only year-end compensation. The full reconciliation was previously presented in the Distribution Application as Attachment 7 and Attachment 8 filed on December 12, 2017 (EB-2017-0049).
b) Within these total compensation tables, for each of the line item amounts and for each year, the total number of employees in a manner that reconciles with the total number of employees information presented in Transmission Payroll Tables	b) For each employee category, Hydro One has provided total number of employees and FTEs for historical years and FTEs for forecast years.
c) Beside the "Total Number of Employees" information described in item (ii), the total company full time equivalent (FTE) information for each of the years 2014-2018 in a format similar to that shown in EB-2017-0049 Exhibit C1/Tab2/Schedule 1, Table1	c) See b).

d) In the total compensation tables, the allocation of total compensation between capital and OM&A for each of the years 2014-2018 in a manner comparable to that shown for transmission only in Undertaking J10.2	d) The current payroll table includes the allocation of compensation to OM&A and Capital
e) As part of the total compensation table, the Pension and OPEB amounts for distribution for each of the years 2014-2018 in a table similar to the table to that effect contained in Undertaking J10.2	e) The current payroll table includes the pension and OPEB amounts
f) A revision of the format used in Undertaking J10.2 to reflect the format of the total compensation tables described in items a) to e)	f) Hydro One revised the format used in J10.2 to reflect total compensation and to incorporate the directions provided in the OEB decision.
g) An exhibit that shows how the allocation factors used to allocate the total compensation amounts between transmission and distribution are derived.	g) The compensation table utilizes the compensation labour splits that are used in the Black and Veatch allocation methodology. The specific allocations can be found in response to undertaking J5.05.

In summary, Hydro One filed complete compensation data in Attachment 6 in EB-2017 -0049. Specifically, this compensation table contains:

- Total yearly compensation for both the Distribution and Transmission businesses and consolidated for Hydro One Networks.
- Expanded compensation elements (e.g. STIP, LTIP, ESOP and Share Grants)
- Year-end headcount, total headcount and FTEs

By filing compensation data in the current application (EB-2019-0082) in the same format as in Attachment 6 in EB-2017-0049, this allows for a complete overview of compensation at the Transmission, Distribution and consolidated level and trending over the baseline compensation data.

Witness: Sabrin Lila, Joel Jodoin

UNDERTAKING J6.1

Reference:

K6.1

Oral Hearing Volume 6, Page 16, Line 7 – Page 18, Line 13

Undertaking:

To review and confirm the numbers in the grey-shaded portions of Exhibit K6.1; to explain the significant increase in labour burdens at row 206, and how that compares to the increase in FTEs and compensation, whether the increases are in tandem or, for example, if you have a 30 percent increase in FTEs and compensation but a 79 percent increase in burdens, to explain the difference.

Response:

Analysis Performed by OEB Staff

Hydro One has reviewed the additional calculations performed by OEB Staff in exhibit K6.1 (including the October 30, 2019 correction by OEB staff to row 238) highlighted in grey and can confirm that they are mathematically correct; however, they do not take into account increasing FTE levels to support the growing Transmission work program. Moreover, the manner in which OEB Staff derived Burden costs (excluding Pension and OPEB) is misleading, as discussed below.

Hydro One completed an FTE-based analysis in J6.1 Attachment 1 (reproduced version of K6.1) in Columns V to AB and provided additional commentary based on a compound annual growth rate (CAGR) per FTE which is the more appropriate way to review compensation costs over the application term.

CAGR Calculation

CAGR is a more accurate representation of the annual growth rate compared to OEB Staff's calculation which does not take into account the compounding impact of inflation. More importantly, Hydro One has normalized the calculation for FTE levels to better represent the actual cost increases which are largely explained by compensation escalation assumptions.

Total Labour Burdens

The "Burden" amounts included in compensation table at lines 6, 17, 36, 46, 60, 70, 87, and 99 are calculated by applying an assumed burden percentage to base pay. The assumed burden is based on Hydro One's estimate of its FTE requirements to execute the Transmission System Plan included in this Application.

The Pension and OPEB burden amounts included at lines 147, 148, 151, 152 are derived differently, as follows:

- 2014 to 2018 are based on actuals; and
- 2019 to 2022 are based on an actuarial valuation dated effective December 31, 2017 which is based on historical FTE numbers and does not consider the same assumptions for future FTE growth as the "Burden" amounts at lines 6, 17, 36, 46, 60, 70, 87, and 99.

OEB Staff has taken the Burdens from lines 6, 17, 36, 46, 60, 70, 87, and 99 and subtracted the pension and OPEB burden amounts included at lines 147, 148, 151, 152, with the resulting analysis at lines 206 and 215. Because these values are based on different assumptions at different points in time, the resulting number that OEB Staff derived for "Other Burdens" is not accurate.

The burden rate that Hydro One assumed for the purpose of calculating the burden dollars excluding Pension and OPEB is provided below:

	2018	**2019**	**2020**	**2021**	**2022**
Burden Rate (excluding Pension and OPEB)	6.1%	6.2%	6.3%	6.3%	6.4%

The burden rate assumed for "Other Burdens" excluding Pension and OPEB is relatively flat year over year from 2018 to 2022. As such, once total burdens excluding Pension and OPEB is normalized for FTE levels, the CAGR per FTE should be relatively flat.

In order to help with any calculations that OEB Staff would like to perform, Hydro One has provided in the table below a comparative Burden for Transmission and Distribution which excludes Pension and OPEB costs consistent with the methodology used to derive the total burden dollars in lines 6, 17, 36, 46, 60, 70, 87, and 99.

Burden Excluding Pension & OPEB ($)	**2018**	**2019**	**2020**	**2021**	**2022**
Transmission	24,527,313	25,723,508	28,134,664	29,303,622	29,276,017
Distribution	25,519,167	29,676,565	28,807,264	29,363,127	30,890,937

UNDERTAKING J6.2

Reference:

F-5-1 Table 3
Oral Hearing Volume 6, Page 32, Line 24 – Page 33, Line 10
Oral Hearing Volume 6, Page 48, Line 3 – Page 49, Line 7

Undertaking:

To provide the OPEB amounts for 2021 and 2022 similar to 2020 in table 3, Exhibit F-5-1.

Response:

This undertaking was satisfied during the oral hearing as the requested OPEB values for Transmission are provided in Exhibit I, Tab 1, Schedule OEB-221 under part (g) of the response. Further discussion in regards to Distribution values is provided under J6.4.

Witness: Samir Chhelavda

UNDERTAKING J6.5

Reference:
K6.3
Oral Hearing Volume 6, Page 72, Line 4 – Page 74, Line 25

Undertaking:
Explain the order of magnitude or provide a sense of what is the bigger driver for the transmission allocated FTEs between distribution application and transmission application.

Response:
Exhibit K6.3 summarizes the difference in Transmission allocated FTEs presented in the Distribution Application (EB-2017-0049) and the current Transmission Application as provided in Exhibit I, Schedule 7, Tab SEC-58. Hydro One notes that the two applications are underpinned by different business plans, the 2017 – 2022 Business Plan was the basis of the EB-2017-0049, while the 2019 – 2024 is the basis for the current application.

The primary drivers behind the changes between the Transmission allocated FTEs are as follows:

1. An increase in Hydro One Networks engineers transferred from Hydro One Telecom. This was not previously contemplated under the Distribution application (EB-2017-0049);
2. An increase in Health, Safety and Environment resources, particularly in light of the helicopter incident. This was not previously contemplated under the Distribution application (EB-2017-0049);
3. Additional resources to support the strategic sourcing initiative. This was not previously contemplated under the Distribution application (EB-2017-0049); and
4. Changes in the Transmission work program.

The first three points noted above are the main drives for the changes in FTE levels.

Witness: Sabrin Lila

UNDERTAKING J6.6

Reference:

J1.1

Oral Hearing Volume 6, Page 83, Line 5 – Page 84, Line 21

Undertaking:

To explain the translation of Progressive Productivity CapEx to In-Service Additions.

Response:

As discussed in Exhibit B-1-1, TSP Section 1.6 Pages 7 and 8, Hydro One has reduced capital costs by an amount identified as progressive productivity, which represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes. As this commitment is to find further efficiencies through additional productivity improvements, the reductions are envelope based. As a result, an assumption had to be completed to translate the capital expenditure envelope reductions, to how assets would be placed in-service.

The impact of the capital Progressive Productivity Placeholder was translated to In-Service Addition impacts using a proportional ratio of Sustainment Capital Expenditures to In-Service Additions based on forecasted envelope level rates over the Plan years.

UNDERTAKING J6.7

Reference:

JT-2.28
Oral Hearing Volume 6, Page 85, Line 22 – Page 87, Line 19

Undertaking:

To check whether the $5 million in Progressive Defined Productivity included at Exhibit JT-2.28 were embedded into the plan for 2019.

Response:

The $5 million Progressive Defined Productivity for 2019 which is evident from JT-2.28 reflects all the defined initiatives for 2019, and as such the dollars were allocated to the related initiatives and embedded within the capital categories in the 2019 bridge year. 2019 is also considered a budget year for the company.

The remaining years (2020-2024) utilize the Progressive Productivity Placeholder approach. Hydro One allocates committed Defined Progressive initiatives to specific drivers in the budget year (currently 2019). As initiatives are defined, they will be assessed within normal planning processes and planned at the appropriate project or program level. The format provided in undertaking JT-2.28 will always track the progress of the Progressive Initiatives in order to maintain consistency and allow for comparability across rate applications, but the detailed Plan will be built up according to where the initiatives land.

UNDERTAKING J7.1

Reference:

K-1.1, p. 3

Transcript Volume 7, October 31, 2019, page 44, line 10 to page 46, line 5

Undertaking:

To update the timeline in K1.1 to include regional or other engagement with Indigenous communities conducted by Hydro One prior to the date the Application was filed, on March 21, 2019.

Response:

As noted in evidence, Indigenous communities in Ontario are not directly connected to the transmission system, however, a number of Indigenous communities are directly connected to Hydro One's distribution system.

Slide 3 of Hydro One's opening presentation for the Oral Hearing has been updated to include First Nations and Métis customer engagement sessions and activities on a number of topics including both transmission and distribution-related issues.

Markers	Date	Description
A	February 9-10, 2017	Provincial Engagement Sessions with First Nation communities Hydro One serves
B	March 29, 2017	Session for OEB Staff and Intervenors (including Anwaatin) from EB-2016-0160 to seek input on customer engagement process
C	May 13, 2017	Provincial Engagement Session with the 29 Community Metis Councils represented by the Metis Nation of Ontario.
D	July 2, 2017	Customer engagement survey concluded. Hydro One asked LDCs that serve First Nations and Métis communities what they felt Hydro One could do to better serve the specific needs of these communities.
E	February 21, 2018	Provincial Engagement Session with First Nation communities Hydro One serves
F	June 2018 to June 2019	**Ongoing Engagement with Indigenous communities:** **11-Jun-18**: 3 Phase Power Workshop with Wabigoon Lake Ojibway Nation, Seine River, Mitaanjigaming and Nigigoonsiminikaaning **16-Jun-18**: Reliability Meeting with Wikwemikong

Witness: Derek Chum

		19-Jun-18: 3 Phase Power Meeting with Wahgoshig **01-Aug-19**: Manitoulin Regional First Nations Engagement Session **27-Sep-18**: Battery Energy Storage System (BESS) Site Visit and Meeting at Aroland First Nation **26-Oct-18**: Reliability Meeting with Mattagami **20-Nov-18**: 3 Phase Power Meeting with Shawanaga **04-Dec-18**: 3 Phase Power Follow up Meeting with Wahgoshig **21-Jan-19**: Reliability Meeting with Six Nations Elected Council **06-Mar-19**: BESS Meeting with Aroland in Toronto **28-Mar-19**: 3 Phase Power and Forestry Meeting with Brunswick House **29-Mar-19**: Reliability Meeting with Mississaugas of Scugog **19-Jun-19**: Conference Call with Animbiigoo Zaagi'igan Anishinaabekto to connect a community in the Beardmore Area (Geraldton Area).

Witness: Derek Chum

UNDERTAKING J7.2

Reference:

A-7- 2, Attachment 3, page 7

Undertaking:

To clarify reliability data given in presentations to First Nations, northern system reliability versus first nations transmission reliability.

Response:

As there are no First Nations directly connected to the transmission system, the data included in the referenced table, reproduced below, is based on the delivery points serving First Nations communities.

Transmission Connections Performance: By Geographic Region
(First Nations Only)

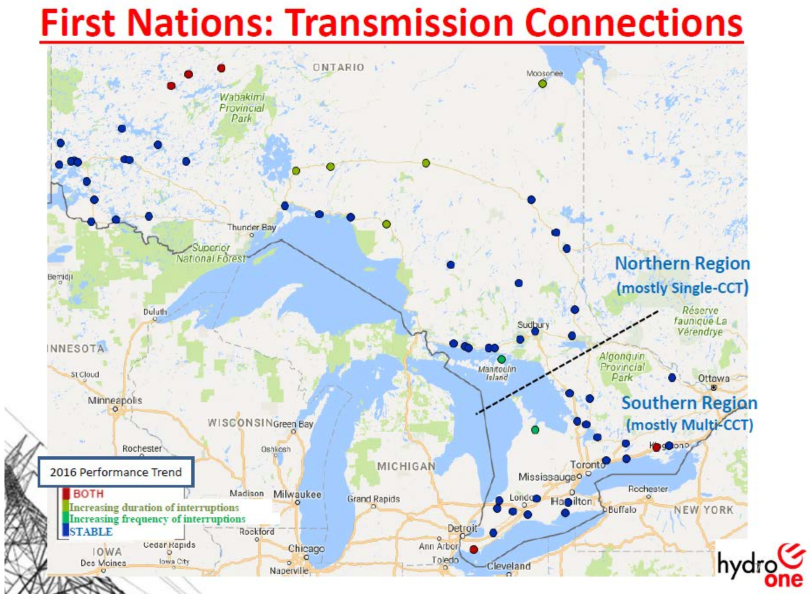
Transmission System - Northern Sub-System (2016 YE Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes/ Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
[1]First Nations	44	216.4 (68.4)	4.48

Transmission System - Southern Sub-System (2016 YE Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes /Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
First Nations	25	25.1	1.20

[1] Two lines account for 58% of total interruption minutes for entire year

Source: Hydro One and First Nations Engagement Session Presentation, February 9 & 10, 2017; filed Exhibit K7.2 Anwaatin Compendium for Panel 3, page 65.

Of the 69 delivery points serving First Nations communities, 44 are located in the Northern sub-system and 25 are located in the Southern sub-system, divided based on the separation shown below:



Source: First Nations – Reliability Performance Overview Presentation, February 21, 2018; filed Exhibit A, Tab 7, Schedule 2, Attachment 3, page 7.

The “Duration of Interruptions (interruption minutes/Tx Connection)” is the average interruption duration per delivery point per year for the 44 delivery points in the Northern region and the 25 delivery points in Southern region. The calculation is similar to T-SAIDI.

The “Frequency of Interruptions (# of interruptions/Tx Connection)” is the interruption frequency per delivery point per year for the 44 delivery points in the Northern region and the 25 delivery points in the Southern region. The calculation is similar to T-SAIFI.

UNDERTAKING J7.3

Reference:

Undertaking:
To file the 2017 Customer Satisfaction Survey.

Response:
Provided as Attachment 1 of this undertaking response is the *2017 Large Tx Customer Satisfaction Summary of Findings*.

Customer Experience

Large TX Customer Satisfaction Summary of Findings

November 28, 2017

Technical Vocabulary Glossary

Throughout the survey, Northstar has presented data graphically, using arrows to represent statistical differences in data, and has crafted recommendations and key insights using technical research terminology. Below is a glossary of terminology and symbols used throughout the report.

- T2B / T4B – The top two box score (on a 5 point scale), or top four box score (on a 10 point scale) is compared throughout the report as a means of streamlining analysis.
- Arrows have been used to distinguish results which are statistically or directionally significant.
  - Findings which are statistically higher or lower (calculated at a 90% confidence level) between years.
  - Findings which are statistically higher or lower (calculated at an 80% confidence level) between years.
- Circles have been used to distinguish results which are statistically or directionally significant between customer groups.
  - Findings which are statistically higher (calculated at a 90% confidence level) between customer groups.
  - Findings which are statistically lower (calculated at a 80% confidence level) between customer groups.

Survey Overview: Tx CSAT

- **Survey Objectives** – To measure key drivers of satisfaction among LTX customers and monitor Hydro One's performance in key service areas.
- **Survey Type** – Measures customers' opinion of the company as a whole (whether they have interacted with Hydro One recently or not). It seeks to uncover perceptions of how well the company is meeting customer expectations and delivering on critical success factors.
- **In-field Dates** – The 2017 Large TX research project was carried out by Northstar and our field partner – Decision Point Research. In 2017, only one wave was conducted for LTX, as opposed to two waves in previous years. Additionally, the survey was condensed this wave – only including questions 2, 10, 18, 19B, 24, 24B, 25, 26, 38 and 39. Field dates for the Large TX study changed in 2017. This wave included Hydro One sending the initial email invitation to all 183 Large TX customers on September 11, 2017. Telephone interviews started on September 18th. E-mail reminders were sent by Hydro One on September 28, with field closing on October 20.
- **Method of Communication** –All interviewing was conducted via telephone followed by computer-assisted telephone interviewing if customer prefers/is not reached.
- **Response Rate** – Of the 183 names provided, 3 had been disconnected / removed, resulting in a sample size of 180. 111 customers answered at least one foundational scorecard question, resulting in a survey response rate of 62% (vs. 64% in 2016).
- **Surveyed Segment** – the below table outlines the surveyed customer types & survey sample size. Please note that two non-responders were undefined in the sample.

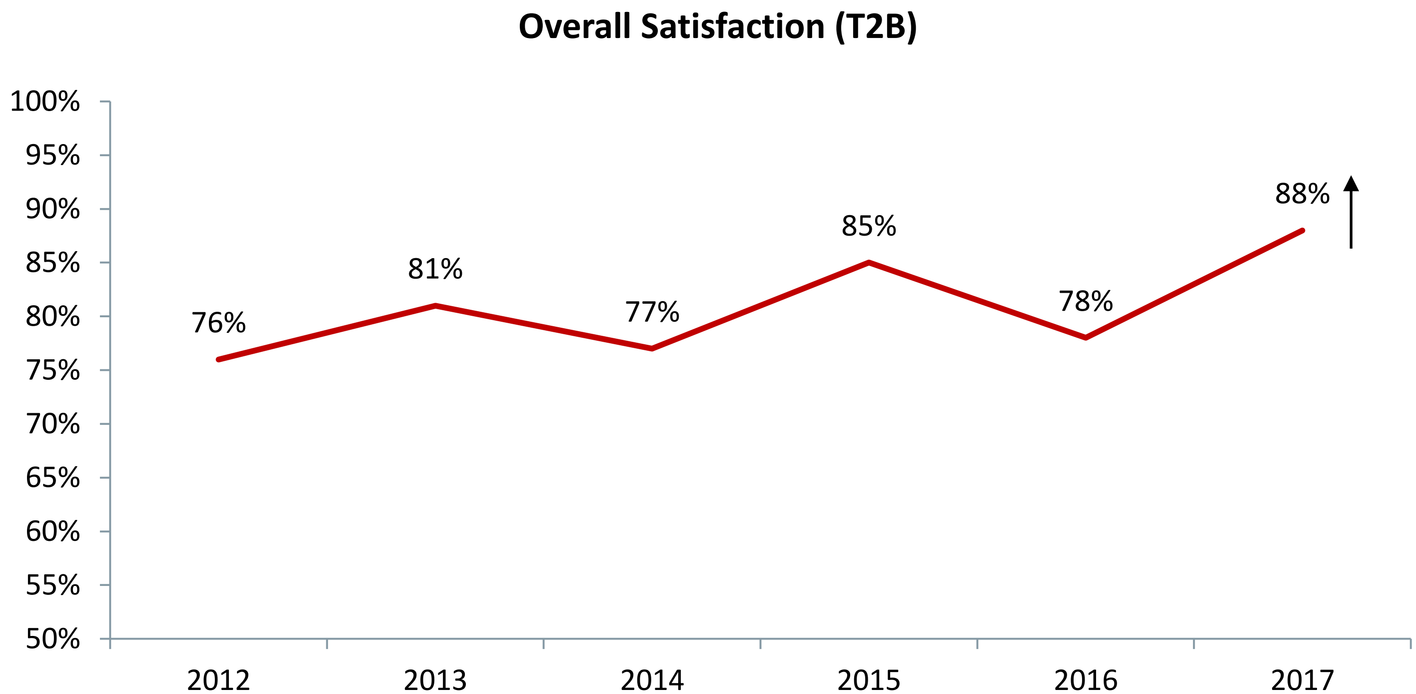
Segment Size	End Users	LDCs	Generators
Total Population Size*	59	66	58
Surveyed (N Value)	29	47	35

*Note: Total Population Size represent the total number of records provided in the sample.

Overall Satisfaction – Survey Results (All Tx)

The survey question reads:

"Overall, how satisfied are you with Hydro One? Would you say you are…?"



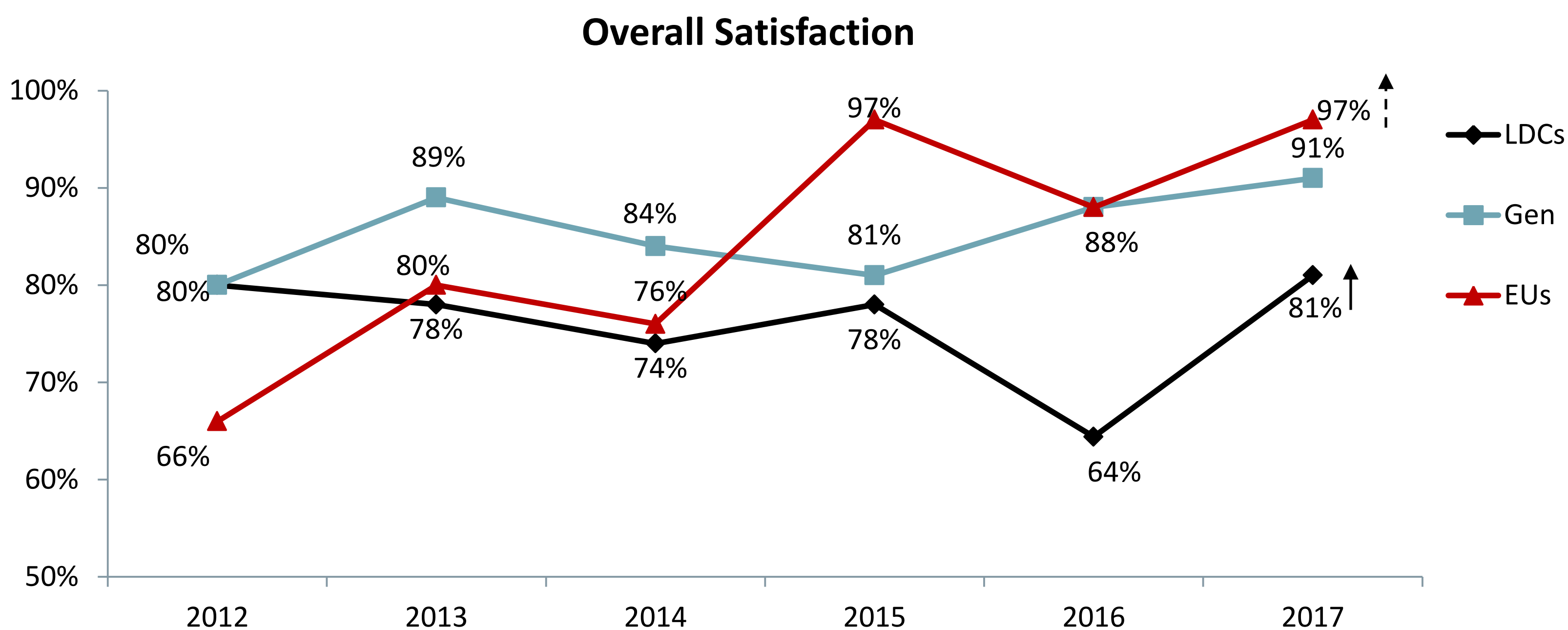
Key Insights

- *Overall satisfaction with Hydro One has increased 10 points over the previous year, with levels at the highest since tracking began in 2012.*

Overall Satisfaction – Survey Results (By Segment)

The survey question reads:

"Overall, how satisfied are you with Hydro One? Would you say you are…?"

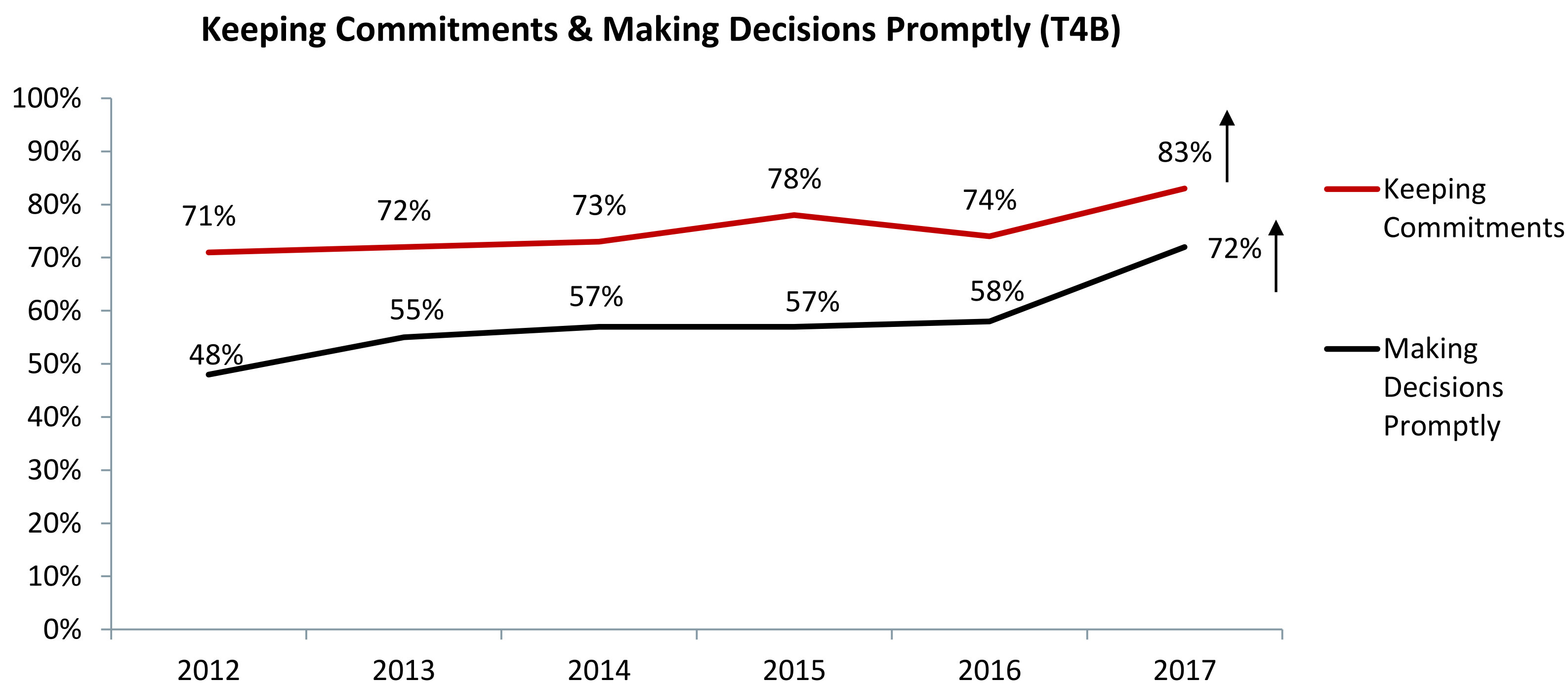


Key Insights

- *The increase in overall satisfaction score can be largely attributed to LDC customers, who show a significant (+17, 81%) increase in satisfaction, reversing the 14 point decline in satisfaction in 2016.*
- *End User customers show a directional increase of 9 points.*
- *Satisfaction for all three customer groups is at its highest since tracking started.*

Scorecard Metrics – Survey Results (All Tx)

The survey questions read:
"How would you rate Hydro One on the following specific attributes… Keeping Commitments and Making Decisions Promptly?"



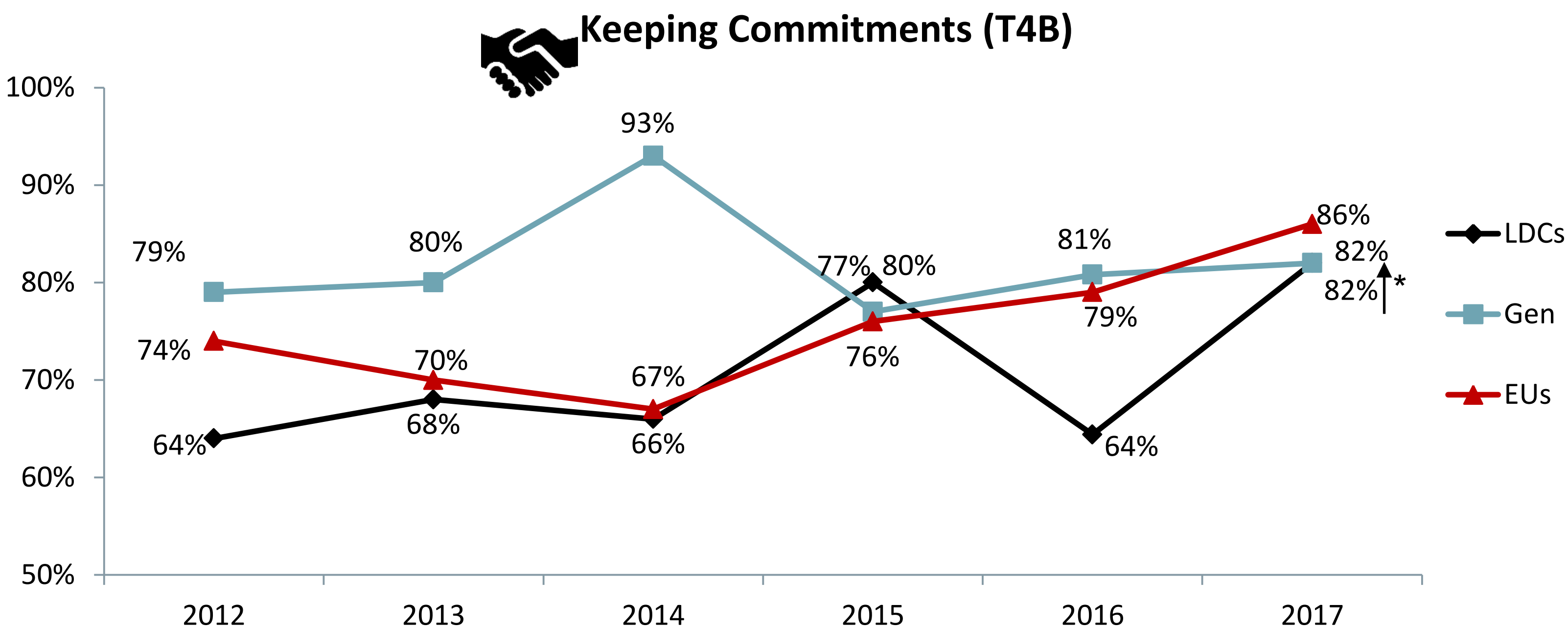
Key Insights

- *Hydro One's performance on both these foundational attributes is now at its highest since tracking began.*
- *Hydro One's ability to make decisions promptly shows a significant 14 point increase over the last year, and its ability to keep commitments shows a significant 9 point increase over the same period.*

Keeping Commitments – Survey Results (By Segment)

The survey question reads:

"How would you rate Hydro One on the following specific attributes… Keeping Commitments?"



Key Insights

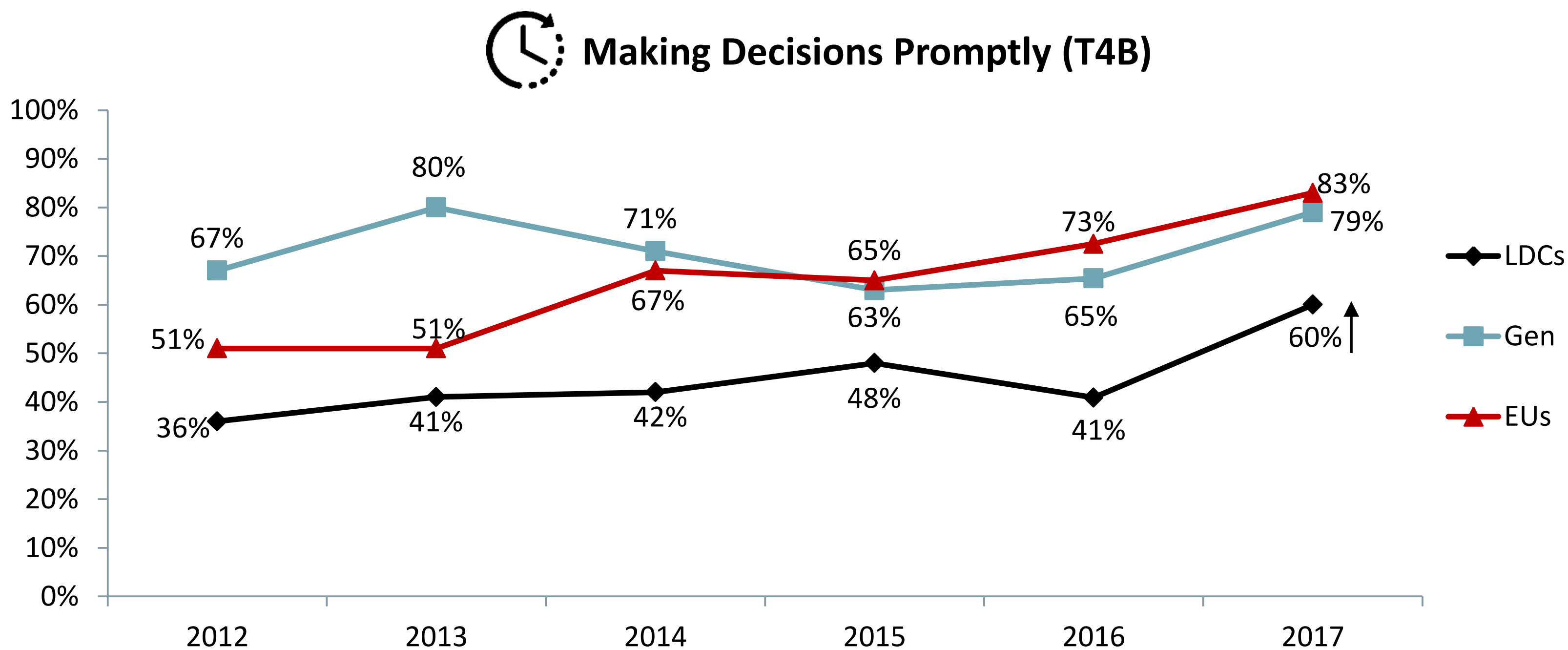
- *Generator customers have historically shown the highest level of satisfaction regarding Hydro One's focus on keeping commitments.*
- *LDCs show a significant 18 point increase in satisfaction regarding Hydro One's focus on keeping commitments, reaching the highest point seen since tracking began.*
- *End Users continue their upward movement, with satisfaction at its highest since tracking began.*

*** Note:** *the arrow in the graph only refers to a significant increase in Keeping Commitments for LDCs.*

Making Decisions Promptly – Survey Results (By Segment)

The survey question reads:

"How would you rate Hydro One on the following specific attributes… Making Decisions Promptly?"



Key Insights

- *LDC customers provided significantly higher ratings for Hydro One's ability to make decisions promptly.*
- *Both End Users and Generators show an increase in satisfaction with Hydro One's ability to make decisions promptly over the last year.*

Survey Findings

Key Findings	Impacted Segment

- **The overall Large TX customer score is 86%, with overall satisfaction at 88%. Both these are at their highest since tracking began, underscoring Hydro One's initiative to improve relations with all three subgroups.**
  - The increase in overall satisfaction can be largely attributed to LDCs (+17, 81%) and End User customers (+9, 97%). Both show a reversal of the previous year's negative shift, with satisfaction ratings climbing back to their highest points since tracking began.
  - Generator customers continue to show consistent satisfaction with Hydro One, with satisfaction ratings rising steadily over the past few waves.
- **Both scorecard metrics show significant improvement over the previous year.**
  - LDC customer ratings of Hydro One are at their highest over time, with a significant increase in satisfaction with HON Keeping Commitments (82%) and Making Decisions Promptly (60%). The latter metric marks one of the largest score improvements this wave.
  - Consistent with 2016, Generators continue to identify product and planning issues (outage planning, infrastructure upgrades) as key areas for HON to address in order to increase satisfaction.
- **Large TX customers are satisfied with their most recent contact experience with their Account Executive.**
  - Generators rate increasing satisfaction with their Account Executive (+12, 97%) while LDCs and End Users show dwindling levels of satisfaction.
  - The Ability to Access HON has decreased this wave. End Users and LDCs provide perfect scores for Easy to Reach [HON] during Unplanned Outages with any questions or concerns.

LDC
End Users
Generators

UNDERTAKING J7.7

Reference:
EB-2014-0140, Settlement Agreement, Section II, p. 24 of 27

Undertaking:
To confirm whether or not the statement in the settlement proposal is factually accurate, in that Hydro One did in fact propose $1.70 per megawatt-hour at that time.

Response:
Hydro One's Application, Evidence and Settlement Agreement in EB-2014-0140 was filed with the OEB on September 16, 2014 and was posted to the OEB website/webdrawer as a pdf document on September 22, 2014.

Exhibit H1, Tab 5, Schedule 1 starting at page 535 of the pdf document provided Hydro One's proposals with respect to Export Transmission Service (ETS). As stated on page 535 of the pdf document, Hydro One proposed to adopt the recommendation of the Elenchus report filed with the Application, Evidence and Settlement Agreement (which was for a $1.70 rate). As stated on page 538 of the pdf document, Hydro One's ETS revenues used for establishing the rates revenue requirement in the application were determined based on the approved tariff at the time of $2/MWh and Hydro One indicated that it would update the ETS revenue to reflect the Board's Decision on ETS as part of the Draft Rate Order process.

UNDERTAKING J7.8

Reference:
I-03-APPrO-003, Part c)

Undertaking:
To update the response to Exhibit I, Tab 3, Schedule 3, to include 1.21 per megawatt-hour.

Response:
Table below provides the updated response to Exhibit I, Tab 3, Schedule 3, to include Export Transmission Service rate of $1.21/MWh.

Response	ETS Rate ($/MWh)	Volume (MWh)	Estimated Revenues	Ontario ETS Revenue Requirement*	Revenue to Cost Ratio
	A	B	C = A X B	D	E = C/D
Interrogatory I-3-3-Part a	1.85	18,800,000	$ 34,780,000	$ 23,532,133	1.48
Interrogatory I-3-3-Part b	1.05	18,800,000	$ 19,740,000	$ 23,532,133	0.84
Interrogatory I-3-3-Part c	1.25	18,800,000	$ 23,500,000	$ 23,532,133	1.00
Interrogatory I-3-3-Part d	1.45	18,800,000	$ 27,260,000	$ 23,532,133	1.16
Undertaking J7.8	1.21	18,800,000	$ 22,748,000	$ 23,532,133	0.97

** Note: 2020 Ontario ETS Revenue Requirement provided in Interrogatory Response I-03-APPrO-001 Part (b)*

UNDERTAKING J7.9

Reference:
I-03-APPrO-004

Undertaking:
To model the rate impact on other customers of $1.21 per megawatt-hour.

Response:
Tables 1 and 2 provide the 2020 bill impacts for typical medium density (R1) Residential and General Service Energy less than 50 kW customers using an assumed Export Transmission Service (ETS) rate of $1.21/MWh.[1]

Table 3 provides the updated summary of bill impacts using an assumed ETS rate of $1.21/MWh.

Table 1: Typical Medium Density (R1) Residential Customer Bill Impacts

	400 kWh	750 kWh	1,800 kWh
Total Bill as of May 1, 2018[1]	$83.40	$121.75	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$8.96	$21.50
Estimated 2019 Monthly RTSR[4]	$5.10	$9.56	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.24**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[5]	$5.56	$10.42	$25.01
2020 increase in Monthly Bill	**$0.46**	**$0.86**	**$2.06**
2020 increase as a % of total bill	*0.5%*	*0.7%*	*0.9%*

[1] Revenue Requirement as per the blue page update filed on June 19th, 2019.

A Table 2: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$198.93	$367.73	$2,562.20
RTSR included in 2017 GSe Customer's Bill (based on 2016 UTR)	$10.63	$21.26	$159.47
Estimated 2019 Monthly RTSR[4]	$11.35	$22.69	$170.21
2019 increase in Monthly Bill	**$0.29**	**$0.58**	**$4.33**
2019 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[5]	$12.37	$24.73	$185.49
2020 increase in Monthly Bill	**$1.02**	**$2.04**	**$15.28**
2020 increase as a % of total bill	*0.5%*	*0.6%*	*0.6%*

Table 3: Summary of 2020 Bill Impacts

	R1 @ 750 kWh		**GSe @ 2,000 kWh**	
	Change in Total Bill ($)	**Change in Total Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**
ETS Rate: $1.05/MWh	$0.88	0.72%	$2.08	0.56%
ETS Rate: $1.25/MWh	$0.85	0.70%	$2.03	0.55%
ETS Rate: $1.45/MWh	$0.83	0.68%	$1.97	0.53%
ETS Rate: $1.85/MWh	$0.79	0.64%	$1.86	0.51%
ETS Rate: $1.21/MWh	$0.86	0.70%	$2.04	0.55%

UNDERTAKING J8.1

Reference:
K-8.4

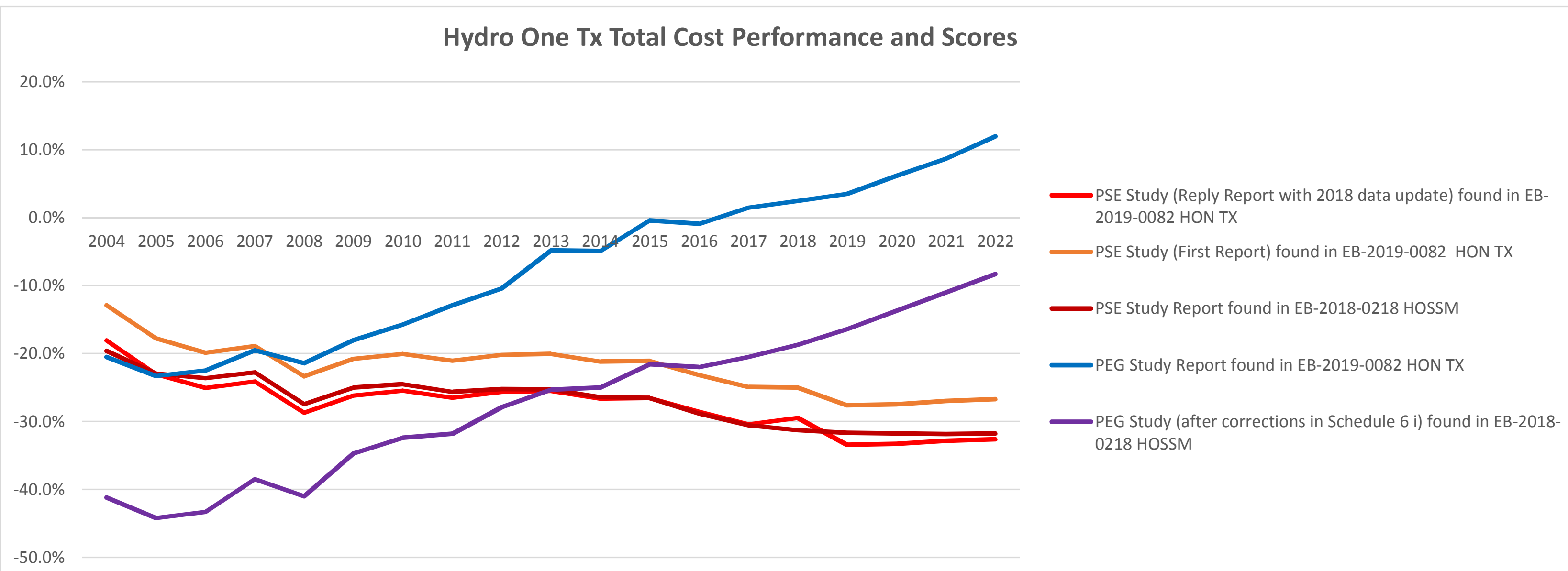
Undertaking:
To provide an updated version of Exhibit K8.4

Response:
Please see attached for an updated version of Exhibit K8.4. As indicated at the oral hearing, this updated version corrects and replaces the Exhibit K8.4 placed on the record at the oral hearing.

Witness: Steve Fenrick

J-8.1

	PSE Study (Reply Report with 2018 data update) found in EB-2019-0082 HON TX	PSE Study (First Report) found in EB-2019-0082 HON TX	PSE Study Report found in EB-2018-0218 HOSSM	PEG Study Report found in EB-2019-0082 HON TX	PEG Study (after corrections in Schedule 6 i) found in EB-2018-0218 HOSSM
2004	-18.1%	-12.9%	-19.6%	-20.5%	-41.20%
2005	-23.0%	-17.8%	-23.0%	-23.3%	-44.2%
2006	-25.1%	-19.9%	-23.6%	-22.5%	-43.3%
2007	-24.1%	-18.9%	-22.8%	-19.5%	-38.5%
2008	-28.7%	-23.4%	-27.4%	-21.4%	-41.0%
2009	-26.2%	-20.8%	-25.0%	-18.0%	-34.7%
2010	-25.4%	-20.1%	-24.5%	-15.7%	-32.4%
2011	-26.5%	-21.0%	-25.7%	-12.9%	-31.8%
2012	-25.6%	-20.2%	-25.2%	-10.4%	-27.9%
2013	-25.5%	-20.0%	-25.3%	-4.8%	-25.3%
2014	-26.6%	-21.2%	-26.4%	-4.9%	-25.0%
2015	-26.6%	-21.1%	-26.5%	-0.4%	-21.6%
2016	-28.6%	-23.2%	-28.9%	-0.9%	-22.0%
2017	-30.4%	-24.9%	-30.6%	1.5%	-20.5%
2018	-29.5%	-25.0%	-31.3%	2.5%	-18.7%
2019	-33.4%	-27.6%	-31.7%	3.5%	-16.4%
2020	-33.3%	-27.5%	-31.8%	6.2%	-13.7%
2021	-32.8%	-27.0%	-31.8%	8.7%	-11.0%
2022	-32.6%	-26.7%	-31.8%	12.0%	-8.3%



UNDERTAKING J8.2

Reference:
JT-2.34-Q9

Undertaking:
To confirm MSP revenue increase as described in JT2.34, Q 9(a).

Response:
The actual 2018 MSP revenue provided in response to undertaking JT2.34, question 9, part a, inadvertently included exit fees along with the meter service fees. The correct amount for actual 2018 MSP revenue is $0.4M.

Witness: Clement Li

UNDERTAKING J8.3

Reference:
I-10-VECC-024

Undertaking:
With reference to VECC compendium, Tab 11, page 5, to provide a link to the IESO's province-wide verified CDM results, or to file the document

Response:
A copy of the report referenced as item 5 in the response to Exhibit I, Tab 10, Schedule 24 part d) is attached in Excel format.

Hydro One notes that this report does not include historical (2006-2014) EE program and C&S savings. As such, it does not provide consistent historical results up to 2018 required for preparing forecasting models, and does not provide consistent bridge and test year data required for load forecast purposes.

Witness: Bijan Alagheband

UNDERTAKING J8.4

Reference:
JT2.34, question 17

Undertaking:
To update undertaking no. JT2.34, question 17 to the end of October

Response:
The table below provides the updated response to technical conference undertaking JT2.34, question 17, covering the period of January to September for 2017, 2018 and 2019. October 2019 ETS export volume is not yet available.

	Actual Export Volume (MWh)		
	2017	**2018**	**2019**
January-September	14,488,262	14,009,258	15,138,054

Witness: Clement Li

UNDERTAKING J8.5

Reference:

J-1.1

Oral Hearing Volume 8, Page 124, Line 13 – Page 128, Line 2

Undertaking:

To provide an updated version of J1.1.

Response:

As a result of the 2020 Cost of Capital Parameters and the updated inflation factor for incentive rate setting for rate changes effective in 2020, issued by the OEB on October 31, 2019, Hydro One has updated the impacted tables from J1.1 to reflect the lower revenue requirement. For the 2020 test year, revenue requirement was further reduced by $39.7 million. Moreover, Hydro One is providing the calculation in Table 3 below to support the inflation factor consistent with evidence in Exhibit A, Tab 4, Schedule 1.

Table 1: Revenue Requirement ($ Millions)
Revised from Exhibit E, Tab 1, Schedule 1 – Table 1

Components	2018[1]	2019[2]	2020 Blue Page	2020 Accelerated CCA[4]	2020 Actual Debt Issuances[5]	2020 Updated Pension Valuation[6]	2020 OPEB ISA Assumptions[7]	2020 Cost of Capital Parameters and Updated Inflation Factor	2020 Cost of Capital Update
OM&A	394.3		375.8			(1.7)			374.1
Depreciation and Amortization	468.6		474.6			(0.1)	0.0		474.5
Income Taxes	57.2		48.3	(23.6)	0.1	1.3	0.1	(8.2)	18.1
Return on Capital	703.6		775.0		(8.3)	(0.2)	0.6	(31.5)	735.6
Total Revenue Requirement	**1,623.8**	**1,644.4**	**1,673.8**	**(23.6)**	**(8.2)**	**(0.7)**	**0.7**	**(39.7)**	**1,602.3**
Deduct External Revenues and Other[3]	(54.7)	(54.5)	(52.6)						(52.6)
Rates Revenue Requirement	**1,569.1**	**1,589.9**	**1,621.2**						**1,549.7**
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	6.8						6.8
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,510.7**	**1,552.3**	**1,628.0**						**1,556.6**

Note 1: Represents OEB approved 2018 revenue requirement from Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160
Note 2: Represents OEB approved 2019 revenue requirement in EB-2018-0130
Note 3: External Revenue and Other includes External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit
Note 4: As quantified in I-1-OEB-208
Note 5: I-04-LPMA-019 reflected a lower cost of debt for 2020 of 4.45% based on 2019 actual issuances relative to 4.57% presented in the blue-page update
Note 6: Updated JT-2.31 Attachment 1 (October 17, 2019) provided the updated pension valuation as of December 31, 2018
Note 7: As quantified in I-01-OEB-206 the revenue requirement impact related to OPEB ISA assumptions
Note 8: 2020 Cost of Capital Parameter and Updated Inflation Factor. Updated inflation factor only impacts 2021 and 2022 revenue requirement.

Table 2: Summary of Revenue Requirement Components ($ Million)

Revised from Exhibit A, Tab 4, Schedule 1 – Table 2

Line		Reference	2020	2021	2022
1	Rate Base	C-1-1	12,407.0	13,130.2	13,951.7
2	Return on Debt	E1-1-1	313.8	332.9	353.7
3	Return on Equity	E1-1-1	421.9	447.5	475.5
4	Depreciation	F-6-1	474.5	503.4	528.9
5	Income Taxes	F-7-2	18.1	18.5	31.2
6	Capital Related Revenue Requirement		1,228.2	1,302.4	1,389.3
7	Less Productivity Factor (0.0%)			-	-
8	**Total Capital Related Revenue Requirement**		**1,228.2**	**1,302.4**	**1,389.3**
9	OM&A	F-1-1	374.1	380.9	387.7
10	**Total Revenue Requirement**		**1,602.3**	**1,683.2**	**1,777.1**
11	Increase in Capital Related Revenue Requirement			74.2	87.0
12	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.63%	5.17%
13	Less Capital Related Revenue Requirement in I-X			1.38%	1.39%
14	**Capital Factor**			**3.25%**	**3.77%**

Table 3: Derivation of Inflation Factor

Revised from Exhibit A, Tab 4, Schedule 1 – Table 1

	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Value - Annual Growth for the 2-factor IPI
Year	**Q1**	**Q2**	**Q3**	**Q4**	**Annual**	**Annual % Change (A)**	**Weight (B)**	**Annual**	**Annual % Change (C)**	**Weight (D)**	**Annual % Change ([A*B]+[C*D])**
2017	108.0	108.5	108.3	109.0	108.45			992.42			
2018	109.4	109.8	110.5	111.1	110.20	1.6%	86%	1021.40	2.9%	14%	1.8%

Table 4: Custom Cap Index (RCI) by Component (%)

Revised from Exhibit A, Tab 4, Schedule 1 – Table 3

Custom Revenue Cap Index by Component	**2021**	**2022**
Inflation Factor (I)	1.80	1.80
Productivity Factor (X)	0.00	0.00
Capital Factor (C)	3.25	3.77
Custom Revenue Cap Index Total	5.05	5.57

Table 5: Revenue Requirement by Year

Revised from Exhibit A, Tab 4, Schedule 1 – Table 4

Year	Formula	Revenue Requirement
2020	Cost of Service	$1,602.3 million
2021	2020 Revenue Requirement x 1.0505	$1,683.2 million
2022	2021 Revenue Requirement x 1.0557	$1,777.1 million

** Calculations assume that Inflation Factor remains at 1.8% through term*

Table 6: Average Bill Impacts on Transmission and Distribution-connected Customers
Revised from Exhibit I2, Tab 5, Schedule 1 – Table 2

	2019[1]	2020		2021		2022	
		Blue Page	CoC Update	Blue Page	CoC Update	Blue Page	CoC Update
Rates Revenue Requirement ($M)	**$1,552.3**	**$1,628.0**	**$1,556.6**	**$1,719.4**	**$1,636.9**	**$1,808.4**	**$1,731.6**
% Increase in Rates RR over prior year		4.90%	0.3%	5.6%	5.2%	5.2%	5.8%
% Impact of load forecast change		3.8%	3.8%	0.6%	0.6%	0.7%	0.7%
Net Impact on Average Transmission Rates		**8.7%**	**4.1%**	**6.2%**	**5.8%**	**5.9%**	**6.5%**
Transmission as a % of Tx-connected customer's Total Bill		*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*
Estimated Average Bill impact		**0.6%**	**0.3%**	**0.5%**	**0.4%**	**0.4%**	**0.5%**
Transmission as a % of Dx-connected customer's Total Bill		*6.2%*	*6.2%*	*6.2%*	*6.2%*	*6.2%*	*6.2%*
Estimated Average Bill impact		**0.5%**	**0.3%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**

[1] 2019 rates revenue requirement as per the OEB's Decision and Order for Hydro One's 2019 Transmission Revenue Requirement application (EB-2018-0130), issued on 25th April, 2019.

Table 7: Typical Medium Density (R1) Residential Customer Bill Impacts
Revised from Exhibit I2, Tab 5, Schedule 1 – Table 3

	Typical R1 Residential Customer					
	Blue Page	**CoC Update**	**Blue Page**	**CoC Update**	**Blue Page**	**CoC Update**
	400 kWh	**400 kWh**	**750 kWh**	**750 kWh**	**1,800 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$83.40	$121.75	$121.75	$236.81	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$4.78	$8.96	$8.96	$21.50	$21.50
Estimated 2019 Monthly RTSR[2]	$5.10	$5.10	$9.56	$9.56	$22.95	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.13**	**$0.24**	**$0.24**	**$0.58**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$5.52	$5.30	$10.35	$9.93	$24.83	$23.83
2020 increase in Monthly Bill	**$0.42**	**$0.20**	**$0.79**	**$0.37**	**$1.89**	**$0.89**
2020 increase as a % of total bill	*0.5%*	*0.2%*	*0.6%*	*0.3%*	*0.8%*	*0.4%*
Estimated 2021 Monthly RTSR[3]	$5.84	$5.58	$10.96	$10.47	$26.29	$25.13
2021 increase in Monthly Bill	**$0.32**	**$0.29**	**$0.61**	**$0.54**	**$1.46**	**$1.30**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.5%*	*0.4%*	*0.6%*	*0.5%*
Estimated 2022 Monthly RTSR[3]	$6.17	$5.93	$11.56	$11.12	$27.76	$26.68
2022 increase in Monthly Bill	**$0.32**	**$0.34**	**$0.61**	**$0.64**	**$1.46**	**$1.54**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.5%*	*0.5%*	*0.6%*	*0.6%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).

[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's 2019 rates revenue requirement as shown in Table 6 above.

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 6above, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

Table 8: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts Revised from Exhibit I2, Tab 5, Schedule 1 – Table 4

	Typical General Service Energy-Billed (<50kW) Customer					
	Blue Page	**CoC Update**	**Blue Page**	**CoC Update**	**Blue Page**	**CoC Update**
	1,000 kWh	**1,000 kWh**	**2,000 kWh**	**2,000 kWh**	**15,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$198.93	$198.93	$367.73	$367.73	$2,562.20	$2,562.20
RTSR included in 2017 GSe Customer's Bill (based on 2016 UTR)	$10.63	$10.63	$21.26	$21.26	$159.47	$159.47
Estimated 2019 Monthly RTSR[2]	$11.35	$11.35	$22.69	$22.69	$170.21	$170.21
2019 increase in Monthly Bill	**$0.29**	**$0.29**	**$0.58**	**$0.58**	**$4.33**	**$4.32**
2019 increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$12.28	$11.79	$24.56	$23.57	$184.20	$176.78
2020 increase in Monthly Bill	**$0.93**	**$0.44**	**$1.86**	**$0.88**	**$13.99**	**$6.57**
2020 increase as a % of total bill	*0.5%*	*0.2%*	*0.5%*	*0.2%*	*0.5%*	*0.3%*
Estimated 2021 Monthly RTSR[3]	$13.00	$12.43	$26.00	$24.86	$195.04	$186.42
2021 increase in Monthly Bill	**$0.72**	**$0.64**	**$1.44**	**$1.29**	**$10.84**	**$9.64**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.4%*	*0.3%*	*0.4%*	*0.4%*
Estimated 2022 Monthly RTSR[3]	$13.73	$13.19	$27.45	$26.38	$205.88	$197.87
2022 increase in Monthly Bill	**$0.72**	**$0.76**	**$1.45**	**$1.53**	**$10.85**	**$11.45**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.4%*	*0.4%*	*0.4%*	*0.4%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).

[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's 2019 rates revenue requirement as shown in Table 6 above.

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 6 above, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

UNDERTAKING J8.6

Reference:

I2-6-2, Attachment 1

Undertaking:

To provide a revised version of Exhibit I2, Tab 6, Schedule 2, attachment 1 with track changes to reflect the removal of solar generators.

Response:

A revised version of Exhibit I2, Tab 6, Schedule 2, attachment 1 is provided as an attachment to this undertaking.[1]

[1] Hydro One notes that the UTRs included in the attached rate schedule are based on the revenue requirement per the Blue Page update filed on June 19, 2019.

2020 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2019-xxxx

The rate schedules contained herein shall be effective January 1, 2020

Issued: Month, Year
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such ~~generation~~ generator unit or energy storage facility are obtained after October 30, 1998; and (b) the generator unit nameplate rating is 2 MW or higher for renewable generation and 1 MW or higher for non- renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage; and (c) the Transmission Delivery Point through which the generator or energy storage facility is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments or expansions approved after October 30, 1998, to a generator or generation facility ~~unit~~ that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental generator nameplate capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for expansion of energy storage facilities. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**4.35**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.83**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.44**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit or energy storage facility for which the required government approvals are obtained after October 30, 1998 and which have installed nameplate capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage, ~~on~~ or the demand supplied by the incremental capacity associated with a refurbishment or expansion approved after October 30, 1998, to a generator ~~unit~~ or generation facility that existed on or prior to October 30, 1998. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

UNDERTAKING J8.7

Reference:
PSE Reply Report filed October 15, 2019

Undertaking:
To provide updated versions of the tables for TFP analysis in the PSE original evidence, that have not yet been updated.

Response:
Please see attached.

Witness: Steve Fenrick

J-8.7

The numbers are slightly different in years prior to 2017 due to input price revisions subsequent to original research. In 2018, Duke Energy Ohio had missing data. We did not include data in 2018 for the company but kept them in the sample prior to 2018 for sample consistency with the original research. If Duke Energy Ohio is excluded entirely, the industry TFP trend is raised by 0.03% to -1.58% for the 2004 to 2018 period.

We note that in the original PSE report, the start year of the sample is reported as 2004. However, PEG reports the growth rates starting in the first "growth rate" year of 2005 rather than the first year of data included in the analysis. To avoid confusion, PSE matched PEG's approach in the Reply Report and we continue that in our response below. For example, the average annual growth rate reported below as 2005 – 2016 has a base year of 2004 but the average growth rates are in 2005 to 2016.

Table 1 Industry TFP and Hydro One TFP

Year	Industry TFP Index	Hydro One TFP Index
2004	1.000	1.000
2005	0.959	1.038
2006	0.995	1.046
2007	1.005	1.021
2008	0.999	1.063
2009	0.992	1.023
2010	0.968	1.009
2011	0.971	1.008
2012	0.954	0.982
2013	0.925	0.971
2014	0.902	0.976
2015	0.868	0.963
2016	0.838	0.969
2017	0.826	0.967
2018	0.799	0.949
2019 (projected)	NA	0.972
2020 (projected)	NA	0.957
2021 (projected)	NA	0.939
2022 (projected)	NA	0.923
Average Annual Growth Rate		
2005-2016	**-1.47%**	**-0.27%**
2005-2018	**-1.61%**	**-0.38%**
2011-2018	**-2.41%**	**-0.77%**
2017-2018	**-2.42%**	**-1.04%**
2021-2022	**NA**	**-1.77%**

Figure 1 Industry TFP and Hydro One TFP

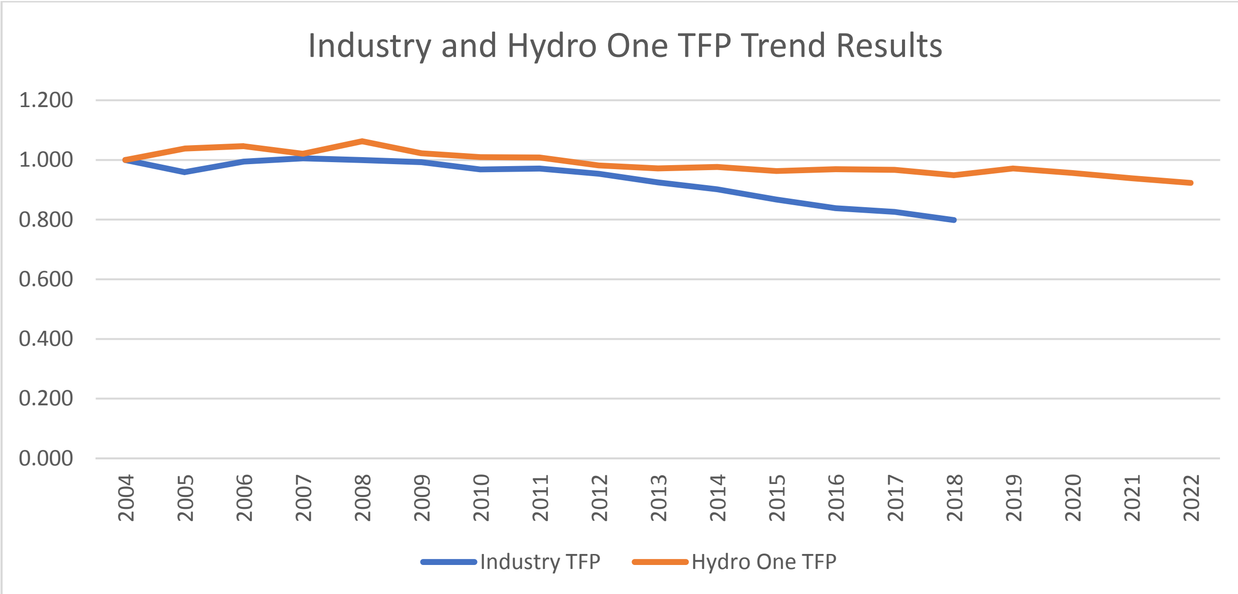


Table 2 Outputs for the U.S. Industry (Sum of Industry)

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	269,938	322,074	1.000
2005	270,606	341,545	1.039
2006	271,519	352,957	1.062
2007	273,730	360,471	1.079
2008	274,995	373,230	1.105
2009	275,529	375,386	1.110
2010	276,661	379,747	1.120
2011	278,122	381,717	1.126
2012	281,442	381,872	1.131
2013	282,314	382,283	1.133
2014	284,859	383,462	1.139
2015	286,866	385,546	1.146
2016	286,274	385,812	1.145
2017	288,818	386,352	1.150
2018	289,275	381,235	1.141
Average Annual Growth Rate			
2005-2016	**0.49%**	**1.50%**	**1.13%**
2005-2018	**0.49%**	**1.20%**	**0.94%**
2011-2018	**0.56%**	**0.05%**	**0.23%**
2017-2018	**0.52%**	**-0.60%**	**-0.19%**

Table 3 Outputs for Hydro One

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	20,603	25,414	1.000
2005	20,547	26,160	1.017
2006	20,625	27,005	1.040
2007	20,624	27,005	1.040
2008	20,661	27,005	1.040
2009	20,658	27,005	1.040
2010	20,676	27,005	1.040
2011	20,694	27,005	1.041
2012	20,891	27,005	1.044
2013	20,904	27,005	1.045
2014	20,882	27,005	1.044
2015	20,948	27,005	1.045
2016	20,949	27,005	1.045
2017 (projected)	20,689	27,005	1.041
2018 (projected)	20,965	27,005	1.046
2019 (projected)	20,967	27,005	1.046
2020 (projected)	20,967	27,005	1.046
2021 (projected)	20,970	27,005	1.046
2022 (projected)	20,974	27,005	1.046
Average Annual Growth Rate			
2005-2016	**0.14%**	**0.51%**	**0.37%**
2005-2018	**0.12%**	**0.43%**	**0.32%**
2011-2018	**0.17%**	**0.00%**	**0.06%**
2017-2018	**0.04%**	**0.00%**	**0.01%**
2021-2022	**0.02%**	**0.00%**	**0.01%**

Table 4 Input Quantities for the U.S. Transmission Industry

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	812,953	2,338,817	1.000
2005	816,873	3,010,246	1.083
2006	825,852	2,806,816	1.068
2007	837,328	2,763,533	1.073
2008	856,872	2,898,901	1.106
2009	876,273	2,843,708	1.119
2010	903,007	2,968,541	1.157
2011	923,140	2,810,525	1.159
2012	951,810	2,802,229	1.186
2013	994,699	2,792,424	1.225
2014	1,040,001	2,742,882	1.263
2015	1,081,752	2,923,110	1.321
2016	1,114,750	3,065,448	1.366
2017	1,143,383	3,060,691	1.393
2018	1,165,471	3,205,374	1.429
Average Annual Growth Rate			
2005-2016	**2.63%**	**2.25%**	**2.60%**
2005-2018	**2.57%**	**2.25%**	**2.55%**
2011-2018	**3.19%**	**0.96%**	**2.64%**
2017-2018	**2.22%**	**2.23%**	**2.23%**

Table 5 Input Quantities for Hydro One

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	137,513	259,756	1.000
2005	137,060	239,556	0.980
2006	135,904	264,144	0.994
2007	136,392	291,855	1.018
2008	135,507	247,012	0.979
2009	137,319	284,640	1.017
2010	140,541	277,211	1.031
2011	142,755	261,372	1.033
2012	148,227	259,444	1.064
2013	149,155	268,572	1.076
2014	151,727	238,857	1.070
2015	151,731	261,093	1.086
2016	153,644	236,655	1.079
2017	155,045	221,972	1.077
2018	158,220	231,148	1.102
2019 (projected)	159,699	184,471	1.076
2020 (projected)	161,608	192,113	1.093
2021 (projected)	165,161	191,928	1.114
2022 (projected)	168,352	191,735	1.133
Average Annual Growth Rate			
2005-2016	**0.92%**	**-0.78%**	**0.64%**
2005-2018	**1.00%**	**-0.83%**	**0.70%**
2011-2018	**1.48%**	**-2.27%**	**0.84%**
2017-2018	**1.47%**	**-1.18%**	**1.05%**
2021-2022	**2.04%**	**-0.10%**	**1.77%**

Table 6 Industry and Hydro One TFP Results

Year	Industry TFP Index	Industry TFP Growth Rate	Hydro One TFP Index	Hydro One TFP Growth Rate
2004	1.000		1.000	
2005	0.959	-4.2%	1.038	3.7%
2006	0.995	3.6%	1.046	0.8%
2007	1.005	1.1%	1.021	-2.5%
2008	0.999	-0.6%	1.063	4.0%
2009	0.992	-0.7%	1.023	-3.8%
2010	0.968	-2.5%	1.009	-1.3%
2011	0.971	0.3%	1.008	-0.1%
2012	0.954	-1.8%	0.982	-2.6%
2013	0.925	-3.1%	0.971	-1.1%
2014	0.902	-2.5%	0.976	0.5%
2015	0.868	-3.9%	0.963	-1.4%
2016	0.838	-3.4%	0.969	0.6%
2017	0.826	-1.5%	0.967	-0.2%
2018	0.799	-3.4%	0.949	-1.9%
2019 (projected)	NA	NA	0.972	2.4%
2020 (projected)	NA	NA	0.957	-1.6%
2021 (projected)	NA	NA	0.939	-1.9%
2022 (projected)	NA	NA	0.923	-1.7%
Average Annual Growth Rate				
2005-2016	**-1.47%**		**-0.27%**	
2005-2018	**-1.61%**		**-0.38%**	
2011-2018	**-2.41%**		**-0.77%**	
2017-2018	**-2.42%**		**-1.04%**	
2021-2022	**NA**		**-1.77%**	

UNDERTAKING J8.8

Reference:

PSE Reply Report filed October 15, 2019

Undertaking:

To provide the statistical model summaries for the total cost benchmarking in the reply report.

Response:

Please see attached.

Witness: Steve Fenrick

J-8.8

The small difference in actual costs due to input price index updates since original research. Duke Energy Ohio was excluded in 2018 due to missing data.

Table 1 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,291,742	$1,547,841	-18.1%
2005	$1,345,894	$1,694,003	-23.0%
2006	$1,440,112	$1,850,193	-25.1%
2007	$1,575,837	$2,005,453	-24.1%
2008	$1,643,735	$2,190,062	-28.7%
2009	$1,754,312	$2,279,231	-26.2%
2010	$1,794,360	$2,314,267	-25.4%
2011	$1,949,822	$2,541,204	-26.5%
2012	$2,059,992	$2,661,677	-25.6%
2013	$2,052,515	$2,648,653	-25.5%
2014	$2,091,997	$2,730,386	-26.6%
2015	$2,185,921	$2,850,894	-26.6%
2016	$2,218,630	$2,952,273	-28.6%
2017	$2,097,418	$2,842,567	-30.4%
2018	$2,282,409	$3,064,682	-29.5%
2019 (projected)	$2,300,462	$3,213,522	-33.4%
2020 (projected)	$2,387,703	$3,331,116	-33.3%
2021 (projected)	$2,486,384	$3,453,237	-32.8%
2022 (projected)	$2,583,385	$3,580,226	-32.6%
Average % Difference			
2004-2018			**-26.0%**
2016-2018			**-29.5%**
2020-2022			**-32.9%**

Figure 1 Hydro One's Cost Performance 2004-2022

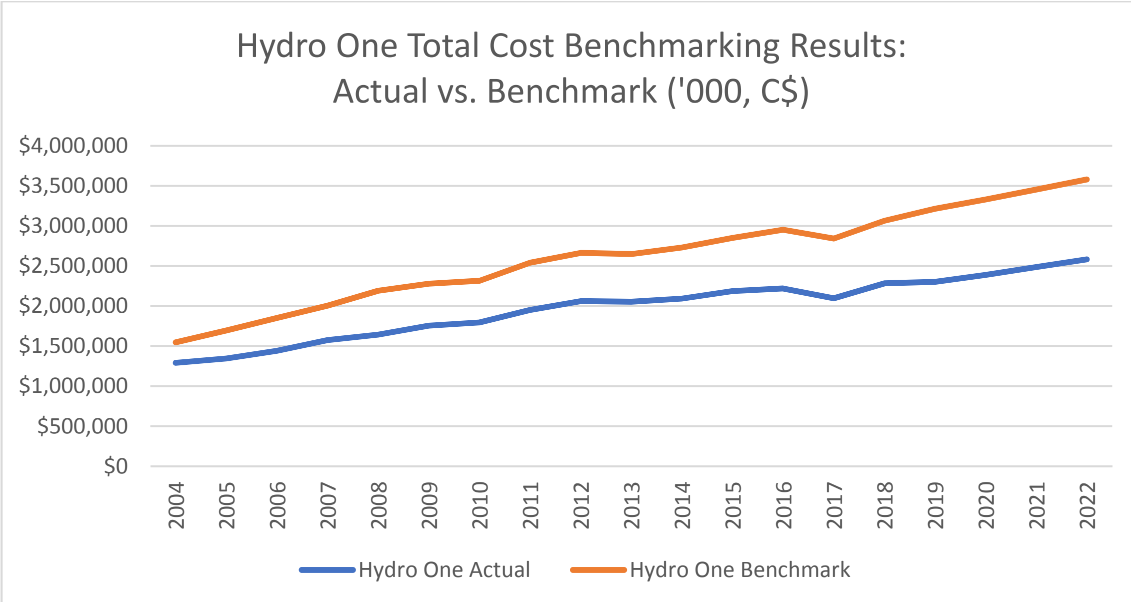


Table 2 Econometric Model Parameter Estimates

Total Cost Model Estimates

VARIABLE KEY

KM = Total transmission Kilometres of line
D = Maximum peak demand
Tx = Percent of transmission plant in total electric utility plant
Cap = Average capacity (MVa) per substation
Sub = Number of transmission substations per KM of line
Volt = Average voltage of transmission lines
CS = Construction standards of building transmission pole
UG = Percent of transmission lines underground
Trend = Time trend (current year minus 2003)

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM	0.353	20.930
KM*KM	0.127	6.080
KM*D	-0.400	-6.770
D	0.615	24.250
D*D	0.364	16.430
Tx	0.533	16.010
Cap	0.160	6.920
Sub	0.113	7.280
Volt	0.210	12.080

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
CS	0.239	6.160
UG	0.729	3.170
Trend	0.014	7.370
Constant	11.671	141.630
Adjusted R-Squared	0.920	
Sample Period:		2004-2022
Number of Observations		839

UNDERTAKING J8.09

Reference:
PSE Reply Report filed October 15, 2019

Undertaking:
To provide the working papers in confidence.

Response:
The working papers will be provided by Hydro One's counsel under separate cover.

UNDERTAKING J9.3

Reference:
I2-06-02-01, 2020 Proposed Uniform Transmission Rate Schedule

Undertaking:
To confirm that the definition of renewables in the schedules is consistent with the Electricity Act.

Response:
Section 2 of the *Electricity Act, 1998* (the "EA") currently defines "renewable energy source" as follows:

> *"renewable energy source" means an energy source that is renewed by natural processes and includes wind, water, biomass, biogas, biofuel, solar energy, geothermal energy, tidal forces and such other energy sources as may be prescribed by the regulations, but only if the energy source satisfies such criteria as may be prescribed by the regulations for that energy source; ("source d'énergie renouvelable")*

Subsection 1(1) of O. Reg. 160/99, the Definitions and Exemptions regulation to the EA provides further definitions in regards to "biofuel", "biogas" and "biomass".

The current definition of "renewable generation" in Section G of Ontario uniform transmission rate schedules is not significantly different from the above-noted EA definition. Hydro One also notes that neither definition lists energy storage as a renewable energy source.

Hydro One proposes that going forward the transmission rate schedules refer to renewable generation as defined in the Electricity Act. Hydro One will make this change, along with its proposal to add a separate reference to energy storage, in the UTR schedules to be provided as part of the Draft Rate Order following the Board's Decision in this application.

Witness: Henry Andre